Future security of power supply in Germany – the role of stochastic power plant outages and intermittent generation

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Future security of power supply in Germany – the role of stochastic power plant outages and intermittent generation

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Highlights

- Future security of power supply in Europe is assessed with an hourly dispatch model
- A statistical analysis is provided using 300 variations of power plant availability
- Hourly power plant availability is found to have high impact on security of supply
- Results show a high relevance of load and renewable energy generation profiles
- Shortfalls may result from a lack of transmission rather than generation capacity

Key Words

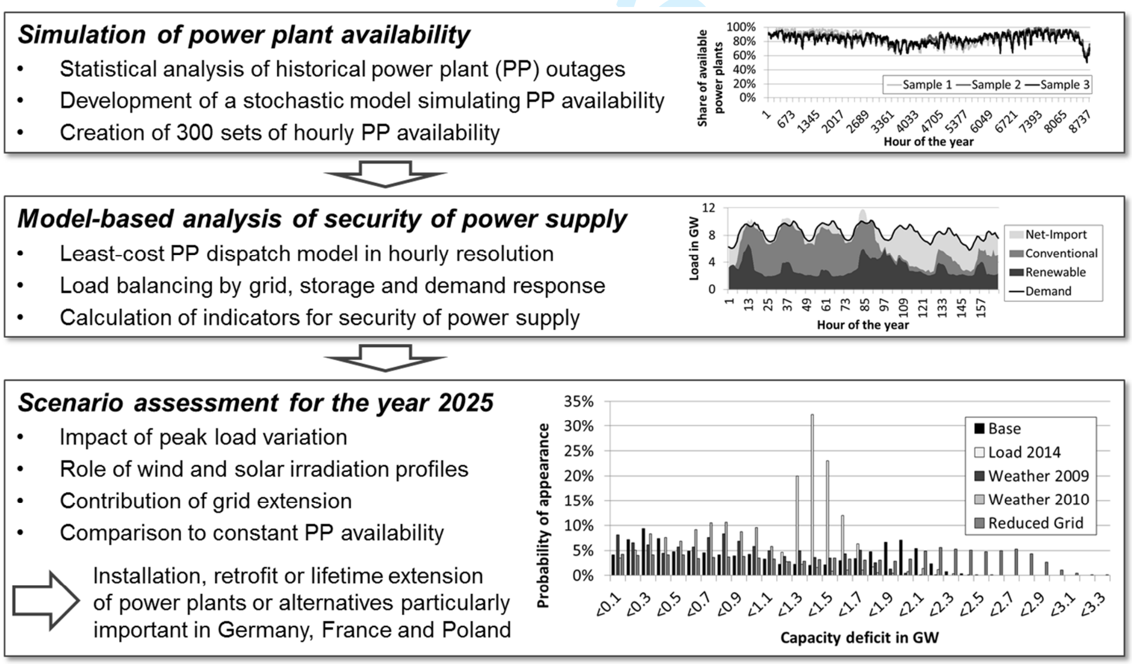
Security of supply, energy system modelling, stochastic power plant outages, variable renewable energy, REMix

Abstract

Many power plants in Germany and Europe are approaching the end of their technical lifetime. Moreover, the increasing wind and solar power generation reduces the operation times of thermal power plants, making future investments in new generation capacity uncertain under current market conditions. Consequently, the future development of security of power supply is unclear.

In this paper, we assess the impact of stochastic fluctuations in power plant availability, renewable generation and grid load on the future security of supply in Germany. We model variations in power plant availability by application of a combined Mean-reversion Jump-diffusion approach. Based on that and using Monte-Carlo methods, we simulate 300 different time series of availability. These profiles are fed into the fundamental power system model REMix, applied to evaluate the appearance of supply shortfalls in hourly resolution. We assess six scenarios for the year 2025, differing in renewable generation and demand profiles, as well as grid infrastructure. Geographical focus of the analysis is Germany, but the electricity exchange with its European neighbours is modelled as well. Our results show that the choice of the power plant availability profile can change the loss of load expectation and loss of load hours by up to 50%. However, the influence of load and renewable generation profiles is found to be significantly higher. Assuming that no new conventional power plants are built and existing plants are decommissioned at the end of their empirical lifetime, we identify supply gaps of up to 2.7 GW in Germany.

Graphical Abstract



1 Introduction

Traditional goals of energy policy are sustainability, competitiveness and security of supply (SoS). Security of power supply and especially the provision of an adequate generation capacity level are of high interest for society and economy. The concept of reliability encompasses two attributes of the electricity system: security on the one hand, which describes the ability of the system to withstand disturbances and adequacy on the other, which represents the ability of the system to meet the aggregate power and energy requirement of all consumers in the future [1].

Whereas the determination of the current SoS is quite a feasible task, the projection of the future SoS or generation adequacy heavily depends on the assumptions made. Most crucial assumptions include the future development of power generation capacity and demand peaks. This also concerns the consideration of planned capacities, which can be quite insecure in their realization.

Another crucial aspect when estimating the future adequacy level is the availability of conventional power plants. Assuming a mean value for availability can lead to an overestimation or underestimation of SoS, as in critical situations a higher or lower level than the expected value of plant failures can occur. Furthermore, the contribution of transnational electricity transmission and variable renewable energy (VRE) sources depend on many factors such as the correlation between local weather and load [2]. Describing the appropriate impact on SoS by single capacity values or simply neglecting it becomes thus insufficient. This especially applies for scenarios of future energy systems relying on high shares of VRE and an increasing power exchange between countries. For regions of the United States studies have examined the system reliability of integrating large wind power generation capacities in the future. However, they rather focused on the stochastic characteristics of weather than the availability of conventional power plants [3,4,5]. Moreover, due to the high dependency on local weather conditions their findings on SoS cannot be generalized or applied to the European energy system. As elaborated in the following, recent studies have been evaluating the current and future SoS in the German and European market. They all consider the available power generation and storage capacities as well as the annual power demand and peak load. Further input includes the amount of interruptible loads and the availability of generation capacities, thus its capability to provide electric power.

ENTSO-E publishes a yearly “Scenario Outlook and Adequacy Forecast” to give an overview of the European electricity system of the members [6]. Two main scenarios are defined; Scenario A is a conservative scenario, considering only power plants that are already under construction, whereas Scenario B considers also planned power plants, implicitly assuming that market signals give enough incentives for investors. The approach follows a static determination of the load balance. For every country and year, two critical times with high load are analysed and the free available capacity is determined. According to [6], the free capacity in the German electricity system becomes negative for the first time in 2018 (Scenario A) and 2021 (Scenario B) respectively. Assuming a net transfer capacity of 17.9 GW which will be increasing up to 27.9 GW, it can be stated that if there is excess capacity in the neighbouring countries, demand can still be covered by imports. The study considers a very low availability of VRE power generation, which potentially leads to an underestimation of the SoS level.

Static load balance approaches give a first indication for the evaluation of generation adequacy. More elaborate evaluations may bring additional benefits for the power system analysis. As Germany is highly integrated in the European grid and market, a national view is not sufficient as well. Power demand and VRE power generation are very volatile, and variations can be balanced within the countries. Thus, the application of models reflecting temporal fluctuations and power transmission is preferable.

A Monte-Carlo Simulation of VRE generation and an hourly market simulation model have been applied in [7]. The loss of load expectation and expected energy not supplied (for definitions see Section 2.3) is computed to evaluate SoS. For Germany there are no hours with lost load in 2015/2016 and 2020/2021. Similarly, generation adequacy for Germany and its electric neighbours for the years 2015, 2020 and 2025 have been computed applying a dynamic analysis with probabilistic elements [8]. The development of power plant capacities is assumed according to Scenario B from [6]. Their results indicate a load balancing probability of almost 100% in all countries and scenario years, except for France and Belgium in the year 2025. Table 1 provides an overview of methodology and results of previous studies.

Table 1: Summary of the considered studies on security of power supply in Europe.

Reference	**[6]**	**[7]**	**[8]**	**[9]**	**[10]**
Time horizon	2015 to 2025	2015/16 and 2020/21	2015, 2020, 2025	2015, 2030	2030
Area	Europe	Europe	Europe	Europe	Italy
Methodology	Static load balance	Optimization, Monte Carlo simulation	Linear optimization and stochastic scenario variations	Linear optimization	Linear/mixed integer optimization
Development of installed capacity	Scenario A: existing capacities and those under construction, Scenario B: also	[6], Scenario A	[6], Scenario B	Endogenous investment decisions	Endogenous

	including planned capacities				
Inner (German) grid restrictions	No	No	No	No	Yes (Italy)
First capacity deficit in Germany	Szenario A: 2018 Szenario B: 2021	None	None	2030 if no investments occur	2030 (Italy)

A methodology for deriving a consistent measure for supply adequacy in the German power sector has been derived in [9], especially considering renewables until 2030. A linear optimization model of the European electricity market is used. However, power imports are not considered as secured capacity. Results show that SoS is assured in the medium term but in the long run additional backup capacities are needed, as VRE technologies can provide secure capacity only to a limited extent. They conclude that a massive construction of gas fired power plants is needed to cover electricity demand until 2030 with sufficient confidence levels. To analyse SoS for the Italian market, an energy system model based on TIMES has been linked with a detailed power system model in [10]. Grid restrictions between the six Italian market zones are considered. The authors claim the results as indicative, as the model development and the linking of the models are still ongoing. They see a loss of load probability of up to 20% in 2030. A different approach is followed in [11]; the author assumes that a growing share of decentralized energy leads to a lower SoS and grid investments are needed. In a cost-benefit analysis, a business-as-usual scenario is compared with a scenario with high renewables which leads to higher costs. None of the existing assessments of the future SoS in Germany considers grid restrictions within the country. This leads to an overestimation of supply security, as regional bottlenecks are not accounted for.

The temporal availability of power generation and storage plants is an important criterion in the evaluation of SoS [12,13]. In fundamental high-resolution power system models, available capacities are often exogenously defined as a static share of the overall installed capacities [14]. In supply systems with increasing share of VRE generation, this approach is not sufficient for an assessment of SoS, as the partially stochastic behaviour of power plant unavailability is not reflected. Unforeseen power plant outages can arise from technical defects of power plant components, transformers or the grid connection, and result in a total or partial curtailment of power generation. If and to what extent supply shortfalls appear then depends on the temporal coincidence of low power plant availability, low VRE generation and high demand. However, power plant outages may also result from foreseeable and thus predictable reasons, including necessary technical revisions and the operating strategy. This fundamental difference between unforeseen and planned power plant outages must be reflected in detailed assessments of SoS.

The scope of this paper is the application of an advanced methodology for the analysis of SoS in a scenario analysis for Germany and its neighbouring countries in the year 2025. It particularly focuses on the analysis of the uncertainty related to the stochastic occurrence of power plant outages and fluctuations in power demand as well as VRE power generation. Its methodological core comprises two parts: the generation of a large number of technology-specific power plant availability time series using a stochastic approach and the scenario-based evaluation of SoS for each of these time series with the high resolution energy system model REMix. The model-based assessment focuses on Germany, but also includes all neighbouring countries as well as Italy, Sweden, and Norway. Grid restrictions are considered not only for international interconnectors, but also between 18 regions within Germany. The methodology and data used are described in detail in Chapter 2 and 3, respectively. Results of the case study analysing the situation in Germany and Europe in the year 2025 for six different scenarios are presented in Chapter 4 and discussed in Chapter 5. Finally, Chapter 6 provides the most important conclusions drawn from the case study.

2 Methodology

The modelling approach consists of two main elements: a stochastic model for simulating hourly power plant availability, and a fundamental power system model for evaluating future SoS.

Compared to reliability assessment approaches that are typically applied to systems consisting of large, dispatchable electricity generation units [12] our approach provides some significant benefits. The stochastic simulation of power plant outages based on historical data improves the analysis with a power system model that considers both time series of power plant availability and load balancing measures such as energy storage and transmission technologies on a geographical scale that goes beyond assessments on country level. Furthermore, for assessing the impact of outages of large power generators the demand that needs to be covered by conventional power plants must be known. Typically, in systems with relevant power supply from VRE this can be derived from the residual load curve. However, this could lead to an underestimation of required power generation from conventional power plants. Due to possibly congested power transmission capacities it appears to be not sufficient to assume that all VRE electricity generation can be fully used for covering the demand. In this study we tackle this issue by performing a simulation of the electricity market with a multi-regional power system model. The actual useable renewable electricity generation for each hour of the year can therefore be considered in the evaluation of the future SoS. In the following, both applied models are introduced in detail.

2.1 Stochastic modelling of power plant availability

The simulation of power plant availabilities relies on the application of a combined Mean-reversion Jump-diffusion approach. Mean-reversion processes – also called Ornstein-Uhlenbeck processes – are stochastic processes used for simulating time series with a tendency to drift towards a long-term mean value [15]. Their behaviour is characterized by a random walk pattern, modified such that the tendency to return to a central location increases with the distance to this location. Jump-diffusion processes are stochastic processes that can be used for simulating time series composed of jumps of different heights [16]. They rely on a Poisson distribution describing the probability of the occurrence of a certain event in a certain period of time. The mathematical description of the Mean-reversion Jump-diffusion simulation approach of power plant unavailability is provided by Eq. 1.

$$S_{t-1} - S_t = \kappa\,(\mu - S_t)\;\Delta t + \sigma_1\;\Delta W_{t,1} + \sigma_2\;\Delta W_{t,2}\;\Delta P_t(\lambda) \tag{1}$$

$S_{t-1} - S_t$: Intertemporal differences in unavailability
κ: Mean reversion rate, describing the stiffness of the Mean reversion process
μ : Mean reversion level, equivalent to the long-term average of the Mean reversion process
Δt : Time step length (in this case one hour, $\Delta t = 1$)
$\sigma_x\;\Delta W_{t,x}$: Values of a Gaussian distribution, scaled with standard deviation σ_x
$\Delta P_t(\lambda)$: Values of a Poisson distribution with expected value and variance λ

The process parameters $\kappa, \mu, \sigma_1, \sigma_2$ and λ are determined based on historical data of power plant unavailability. The model analyses hourly changes in the recorded power plant unavailability and parameterizes the simulation accordingly. This implies that the simulated Mean-reversion Jump-diffusion process reflects the behaviour observed in the past. The model is parametrized independently for different power plant technologies on the one hand, and three classes of power plant outage durations. The latter are merged after each simulation, in order to obtain one profile of power plant unavailability for each technology. The data used for calibrating the model is introduced in Section 3.1.

Using Monte-Carlo methods, the simulation is run V = 300 times for each power plant technology and outage duration class, generating the corresponding amount of samples for the power plant unavailability distribution function on the basis of uniformly distributed random numbers. Each sample consists of T = 8760 values, one for each hour of the year. In contrast to the simulation result, actual distributions of power plant unavailability exhibit an asymmetric shape. This follows from the fact that unavailability values have a lower boundary, as they cannot be negative. However, the average value of the underlying stochastic process can be smaller than zero. For this reason, an asymmetric accumulation of the simulated differences is considered.

For each variation v, technology x, and time step t it follows Eq. 2 and Eq. 3. According to Eq. 2, simulated unavailability values are only considered if they are equal or greater than the minimum of the historic time series Q_t used for the calibration of the model. In the opposite case, they are set to zero for the corresponding hour.

$$S^{*}_{t,x,v} = \begin{cases} S_{t,x,v}, & \forall\ S_{t,x,v} \geq \min\limits_{t\in T, Q_t \neq 0} Q_t \\ 0, & \forall\ S_{t,x,v} < \min\limits_{t\in T, Q_t \neq 0} Q_t \end{cases} \qquad (2)$$

Equation 3 assures that a jump is considered only if the value of the Poisson distribution $\Delta P_t(\lambda)$ is greater or equals a significance limit , which is represented by a value between zero and one (in Eq. 3 stated as p) times the maximum of all simulated Poisson values. If this is not the case, the previous value of unavailability is used again in the current time step.

$$S^{**}_{t,x,v} = \begin{cases} S^{*}_{t,x,v}, & \forall\ \Delta P_t > p \cdot \max\limits_{t\in T} \Delta P_t \\ S^{*}_{t-1,x,v}, & \forall\ \Delta P_t \leq p \cdot \max\limits_{t\in T} \Delta P_t \end{cases} \qquad (3)$$

2.2 *REMix modelling approach*

In the second modelling step, a methodology is required which first provides a time dependent dispatch profile of power generation technologies of an integrated energy supply system. Second, technologies for temporal and spatial load shifting such as transmission grids or energy storage systems need to be considered in order to cover the electricity demand with the whole set of technological options given in a real energy system. Traditional duration curve based approaches [12] do not meet the second requirement, especially for energy systems with increasing shares of intermittent and spatially distributed electricity generation by VRE. Therefore, in the current case study the energy system model REMix [17] is applied. Typically, this kind of energy system models is used for assessing flexibility requirements in renewable based energy systems [18,19]. REMix provides both, the calculation of technical potentials for renewable energy sources as well as the assessment of economic potential by minimizing the total system costs subject to technical and physical constraints. Although it is applicable for capacity expansion planning, the focus for evaluating SoS lies on an optimal hourly system operation for a specific model run. In this work, the model description is limited to those equations and inequalities relevant for the definition of SoS indicators in Section 2.3. A detailed description of the power generation, storage, and direct current transmission technology representation as well as the model's objective function appears in [17].

196 Additionally to the model description provided there, the model version applied in this
197 work considers alternating current transmission using a direct current power flow
198 approach [20]. To consider the hourly technology specific availability of power plants
199 from Section 2.1, the maximum output power constraints in the model are modified to
200 be time dependent according to Eq. (4). To each model region n, a different
201 stochastic availability time series is applied.

$$p_{n,t,x} \leq \hat{P}_{n,x} \cdot \left(1 - S^{**}_{n,t,x} \right)$$
$$p_{n,t,x} \geq 0 \tag{4}$$
$$\forall t \in T, n \in N, x \in X$$

$\hat{P}$: Installed capacity
p: Variable of energy provision, including power generation, import, and storage discharging
n: Index of model regions N
t: Index of time steps T
x: Index of technologies X

202 Consequently, in addition to time series of electricity generation by VRE, regional
203 load profiles and technological and economic parameters, time series of the hourly
204 power plant availability for each technology x and region n are inputs of the
205 operational optimization.

206 For ensuring that power generation and consumption are equal for each time step t
207 an artificial electricity generator $g_{n,t}$ is introduced to the power balance constraint in
208 Eq. (5).

$$\sum_{x=1}^{X} \left(p_{n,t,x} - d_{n,t,x} \right) + g_{n,t} = l_{n,t}$$
$$d_{n,t,x} \geq 0 \ , \ g_{n,t} \geq 0 \tag{5}$$
$$\forall t \in T, n \in N$$

d: Variable of electricity demand, including exports, storage charging, storage losses, and transmission losses
l: Total load
g: Variable of artificial electricity generation

209 By assigning the highest specific costs to the artificial electricity generator, the
210 occurrence of values $g_{n,t} > 0$ indicates that all options for power provision are
211 exhausted, which can be interpreted as a situation of uncovered load. Therefore, the
212 primary results of each model run are the amount and the frequency of uncovered
213 load in one computed year (Figure 1).

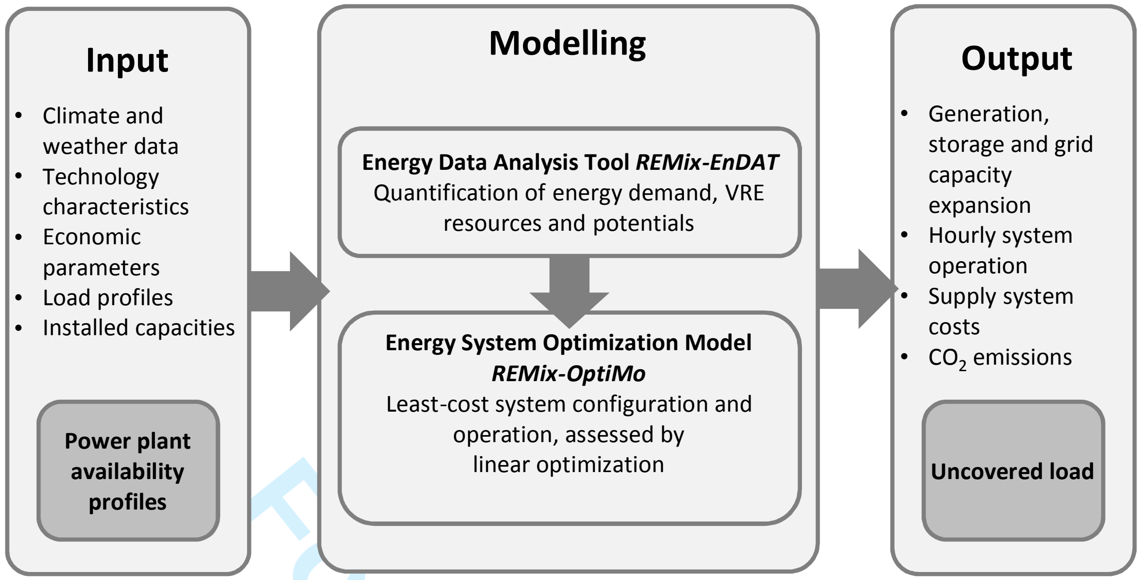


Figure 1: REMix model components and structure. The specific inputs and outputs for the evaluation of system reliability are highlighted in extra boxes.

2.3 Power supply security indicators

Using the $V = 300$ different sets of power plant availability obtained according to Section 2.1, the SoS is assessed by the application of the REMix model. In doing so, one model run – in the following labelled as variation v – is performed for each scenario ω and power plant availability simulation. Since the optimization aims at a least-cost solution and artificial electricity generation causes heavy fines, power supply outages are tried to be avoided. The analysis of SoS relies on the hourly values of uncovered load in each region. Based on the whole of 300 variations for each scenario, five different system adequacy measures are derived. Besides the typical annual loss of load indicators the intensity of these events is assessed in terms of missing power generation (capacity deficit) as well as with regard to not supplied energy (expected energy not supplied):

The **capacity deficit** (CD) is determined with respect to the uncovered load *g* in each model region, scenario, hour and variation. It allows for the identification of the maximum supply gap during the year.

$$CD_{n,\omega} = \max_{t \in T, v \in V} g_{n,\omega,t,v} \quad , \forall\, n \in N, \omega \in \Omega, \tag{6}$$

ω: Index of scenarios Ω

v: Index of variations V

As the availabilities of generation capacities are already considered as input parameter of the power system modelling step, the **loss of load probability** (LOLP) is determined differently compared to conventional approaches that use capacity outage probability tables [12]. Instead, time series with hourly LOLP values are generated for each region using the variable g of artificial electricity generation. However, its meaning remains the risk of a supply shortfall in each hour of the year. It is calculated for each model region, scenario and hour as the ratio of the number of variations with a capacity deficit and the overall number of variations.

$$LOLP_{n,\omega,t} = \frac{1}{V}\sum_{v=1}^{V} \tilde{g}_{n,\omega,t,v} \quad ,\forall\, n \in N, \omega \in \Omega, \mathrm{t} \in \mathrm{T}$$

$$\text{with: } \tilde{g}_{n,\omega,t,v} = \begin{cases} 1 & ,\forall g_{n,\omega,t,v} > 0 \\ 0 & ,\forall g_{n,\omega,t,v} = 0 \end{cases} \tag{7}$$

The **loss of load expectation** (LOLE) represents the number of hours with uncovered load in each model region and scenario:

$$LOLE_{n,\omega} = \sum_{t=1}^{T} LOLP_{n,\omega,t} \quad ,\forall\, n \in N, \omega \in \Omega \tag{8}$$

The **expected energy not supplied** (EENS) is calculated as the overall sum of uncovered load over one year in each scenario and model region. Based on the V = 300 variations, meaningful average values, as well as probability distributions can be calculated for CD, LOLE and EENS.

$$EENS_{n,\omega} = \frac{1}{V}\sum_{v=1}^{V}\sum_{t=1}^{T} g_{n,\omega,t,v} \cdot \Delta t \quad ,\forall\, n \in N, \omega \in \Omega \tag{9}$$

In order to assess the power system's capability to balance load and intermittent power generation from renewable energy sources with the given technological balancing options we also define the **load balancing probability** (LBP) according to [8]. It is calculated from the ratio of LOLE and overall number of T = 8760 hours. It considers all variations of power plant outages at a time and provides one value for each scenario and model region.

$$LBP_{n,\omega} = 1 - \left(\frac{1}{V \cdot T}\sum_{v=1}^{V}\sum_{t=1}^{T} \tilde{g}_{n,\omega,t,v}\right) \quad ,\forall\, n \in N, \omega \in \Omega \tag{10}$$

3 Model input data and scenarios

This chapter provides an overview of the data input of the models. It introduces the historic data used in the parametrization of the stochastic model of power plant availability (3.1), the future development of the power system (3.2), and the scenarios assessed (3.3).

3.1 *Input data to the modelling of power plant availability*

The model used for the stochastic simulation of power plant availability is calibrated using historic data. Since 2013, power plant operators in Germany have to report their planned and unplanned unavailability to the European Energy Exchange [21]. This information includes specifications of the affected power plant block, control area, time, duration and amount of unavailable capacity. This data allows for the simulation of stochastic distributions of future power plant availability with a similar pattern. Table 2 summarizes the minima, maxima and averages of absolute and relative unavailability of power stations in Germany during the years 2013 and 2014 according to the reported data. During this period, the overall unavailability of dispatchable power plants reaches up to 18% of the installed capacity for unplanned outages and up to 40% for planned outages.

Table 2: Reported power plant unavailability in Germany during the years 2013/2014, subdivided by power plant fuel according to [21] in absolute values and relative to the net capacity. Total net capacity and number of events refer to the year 2014.

Technology	Unplanned unavailability			# of events	Planned unavailability			# of events	Total net capacity
	Minimum	Average	Maximum		Minimum	Average	Maximum		
Lignite	20 MW	499 MW	2.560 MW	567	66 MW	2.584 MW	9.665 MW	993	20.443 MW
	0%	2%	12%		0%	13%	47%		
Hard coal	30 MW	1.193 MW	5.143 MW	752	25 MW	2.957 MW	12.284 MW	873	29.607 MW
	0%	4%	18%		0%	10%	42%		
Natural gas	100 MW	565 MW	2.894 MW	121	539 MW	3.297	8.099 MW	458	23.996 MW
	0%	3%	14%		3%	16%	40%		
Oil	37 MW	179 MW	772 MW	21	120 MW	357 MW	1.134 MW	152	3.629 MW
	1%	7%	31%		5%	14%	45%		
Nuclear	10 MW	508 MW	1.567 MW	26	80 MW	2.277 MW	4.744 MW	96	12.068 MW
	0%	4%	13%		1%	19%	39%		
Reservoir hydro	72 MW	381 MW	860 MW	17	30 MW	381 MW	620 MW	36	1.266 MW
	6%	30%	68%		2%	30%	49%		
Pumped storage hydro	55 MW	245 MW	1.680 MW	124	55 MW	892 MW	3.552 MW	293	5.471 MW
	1%	4%	30%		1%	16%	63%		

The historic data reflects the characteristics of both planned and unplanned power plant unavailability. Planned outages result from revisions and operation strategies, whereas unplanned outages arise from technical defects. This distinction between planned and unplanned power plant unavailability is made as well in the model. For planned outages, we assume the same temporal pattern as it has been reported in the year 2014. On the contrary, unplanned outages are simulated in Monte-Carlo method applying the Mean-reversion Jump-diffusion approach introduced in Section 2.1. In doing so, four different power plant technology classes are considered separately: nuclear, lignite-fired and coal-fired power plants, as well as combined cycle power plants (CCGT) relying on natural gas. Pumped storage hydro stations need to be charged to be available for power generation and are limited in their discharging duration; given these special characteristics, we assume a constant availability during the year. The same assumption is made for hydro stations and oil-fired power plants, which do not have a significant share in the overall power plant park. As unplanned outages are rarely reported, we only consider planned outages for nuclear power stations. Table 3 summarizes the assumptions on power plant availability.

Table 3: Consideration of outages by power plant technology class.

	Unplanned unavailability	Planned unavailability
Lignite	Modelled	Historic data
Hard coal	Modelled	Historic data
Natural gas CCGT	Modelled	Historic data
Oil	Not considered	Constant
Nuclear	Not considered	Historic data
Reservoir hydro	Not considered	Constant
Pumped storage hydro	Not considered	Constant

The reported power plant outages differ significantly in their duration. Figure 2 shows the relative frequency of events, as share of total events and weighted with the corresponding unavailable capacity. Most outages last for less than one day. However, there are also a few that stretch over more than a week. Based on the reported data, three different classes of outages are considered in the Monte-Carlo simulations, distinguishing events of lasting for less than one day, between one day and seven days, and longer than seven days. The model is parametrized separately for each power plant technology class and unavailability duration class. Given that the simulated unavailability profiles are applied to all power plants within a country or model region (see Section 3.2), this procedure can be considered a top-down approach. As data on power plant unavailability of a comparable level of extent and detail is not publicly available for other countries as well, the calibration of the model only relies on the reported data from Germany.

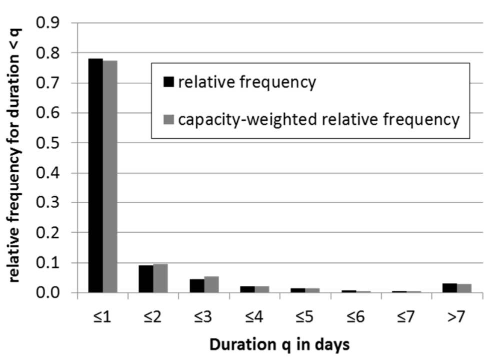


Figure 2: Relative frequencies of the reported unplanned power plant unavailability.

Historic and simulated data show a high congruency. This is shown exemplarily for the relative frequency and relative cumulative frequency of one simulation run for the unavailability of coal-fired power plants with duration between one and seven days in Figure 3. The resulting profiles of power plant outages are shown exemplarily in Figure 4. When comparing historic and simulated data, it has to be considered that the data basis for calculating historic distribution functions only consists of two-years-data. As no long-term unavailability data is available yet for the European electricity generation and as comprehensive announcements of all power plant operators cannot be guaranteed, the simulative distributions do not have to be totally congruent with historical distributions but should be within reasonable distances hereunto. Moreover, each simulation run results in a slightly changed frequency distribution.

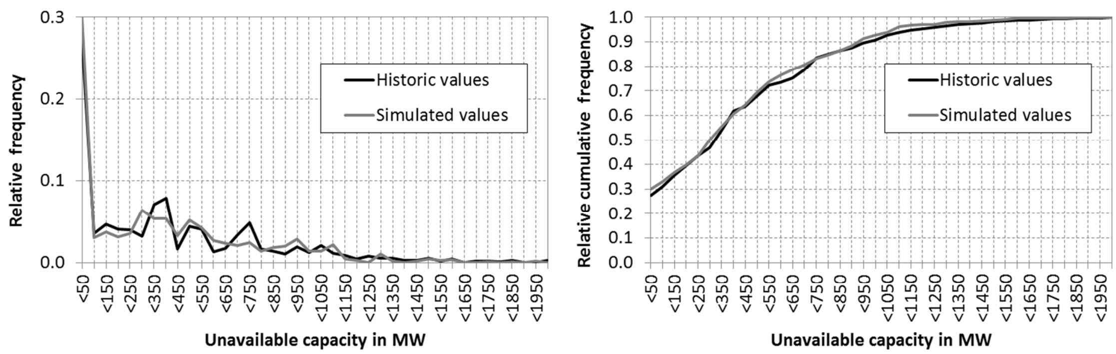
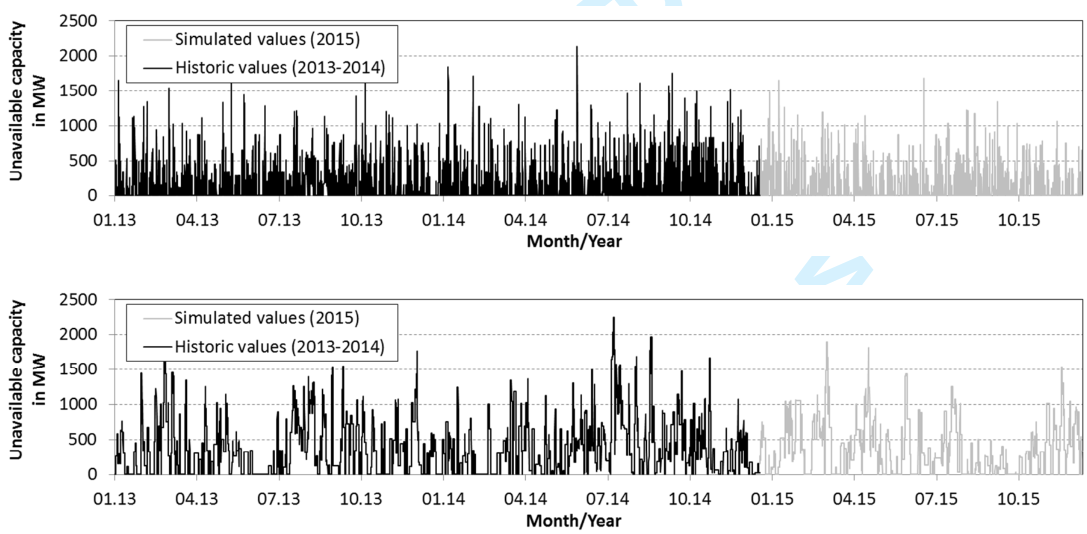


Figure 3: Exemplary comparison of historic and simulated unplanned outages with durations between one and seven days of coal-fired power plants.



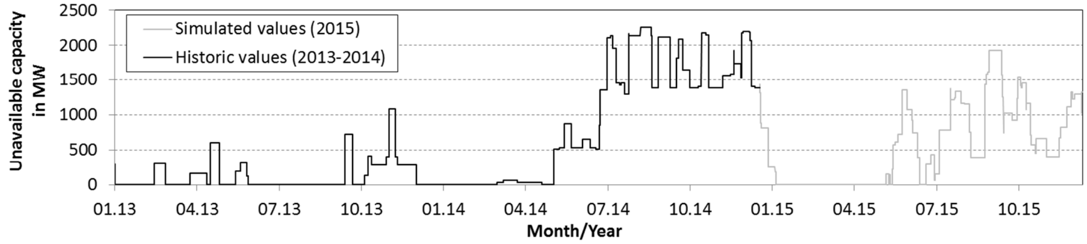


Figure 4: Exemplary results of the simulation of unplanned power plant unavailability. Results are shown for coal-fired power plants and durations of less than one day (top), between one and seven days (centre) and longer than seven days (bottom). The reported historic data is shown in blue, the simulation results in red.

For further processing, the simulated profiles are normalized with the installed power plant capacity of the corresponding technology, thus to values between 0 and 1. For each power plant technology and outage duration class, V = 300 Monte-Carlo simulations are performed. To consider outages with different duration, the resulting profiles are than multiplied for each time step and power plant technology. These aggregated availability profiles are considered in REMix in the subsequent step of the analysis.

3.2 REMix input

In accordance with [22], REMix is parameterized making assumptions for the development of the power system in Germany and its neighbouring countries until the year 2025. Due to the important role of interregional and international power transmission, the REMix application is not limited to Germany, but includes all nine neighbouring countries as well as Norway, Sweden and Italy. The selection of countries is driven by their relevance for the power export and imports of Germany. Due to the very limited transmission capacity to France and long distances to Germany, the influence of the Iberian and British power markets is rather small. Furthermore, the annual power exchange between France and Germany is roughly balanced. In contrast, both concerning the available transmission capacity and the current power export, Italia (via Switzerland) is comparatively more important to the situation in Germany [23]. Within Germany, the SoS is assessed separately for the 18 transmission grid regions used in [24] and shown in Figure 5. Limitations in grid net transfer capacities are considered at country border interconnectors, as well as between the regions in Germany. We assume grid capacities according to the current status and the grid extension scheduled in the German *Netzentwicklungsplan* [25], and the European *Ten Year Network Development Plan* [26]. Limitations in power transmission within the countries of the *Nordel* grid (Norway, Sweden and eastern Denmark) are considered. The assumed transfer capacities are listed in Table 5 in the Appendix.

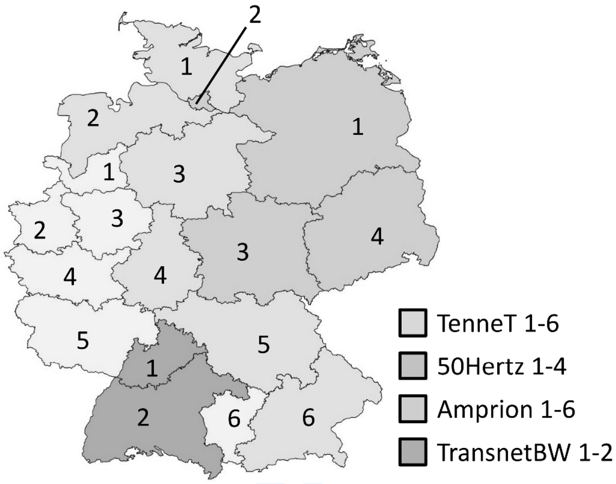


Figure 5: Model regions considered in the REMix application.

The SoS is to a high degree dependent on the annual peak load and the installed power plant capacities. Annual peak loads are calculated from the assumed annual electricity demand and normalized hourly profiles. We assume that efficiency measures allow for an average annual reduction of the electricity demand in the assessed countries by about 1%. The projection of future power plant capacities relies on two separate approaches: for renewable energy technologies as well as small CHP (< 5 MW) a capacity expansion is considered, whereas for conventional power plants a reduction of the current capacity due to decommissioning is considered. The assumed capacity expansion of renewable and CHP technologies relies on different scenario studies for Europe [27], Germany [25], as well as regions in southern Germany [28,29]. The development of conventional power generation capacities relies on an analysis of the current power plant park and empirical data of technology lifetimes [30,31,32,33]. Lifetimes are calculated separately for different fuels and technologies using the available data. We assume that power plants are decommissioned after reaching their technical lifetime. To all power plants that have already passed the average lifetime of the corresponding technology a longer lifetime is assigned based on empirical data. New power plant capacities are only considered to the extent they were already under construction in the year 2014. Power plant decommissioning for economic reasons is not considered. The assumed limits in technical lifetimes and their application to all power plants lead to a significant reduction in available capacities until the year 2025. In the overall assessment area, the reduction amounts to about 36% compared to the year 2015. Particularly high values are reached in Denmark, Sweden and Poland, whereas the Netherlands and the Czech Republic are much less affected. Table 6 in the Appendix provides the lifetimes obtained for different power plant fuels. To reduce the model complexity, conventional power plants are aggregated to five technology classes: nuclear, coal, lignite, gas turbines and CCGT. The latter includes also units running on oil or other fuels. Power plants with optional CHP operation are treated as conventional stations. This implies the assumption of a power-controlled operation and thus availability of additional heat producers as CHP backup, which is also applied to small CHP units.

The consideration of electricity storage is limited to the pumped hydro storage capacity already existing or under construction. Both generation and storage capacities are considered with their net capacity. Another measure for reducing generation capacity is demand response [34,35]. In this work, load reduction potentials in industrial processes are considered. They are determined based on [36,37,38].

To account for the provision of spinning and non-spinning reserve, we reduce the overall power plant and storage capacities by the operating reserve required in the year 2013. In doing so, we assume that the reserve demand amounts to 20 GW in the overall study area (5 GW in Germany) and remains constant in the future. These values are kept constant throughout the year. Reductions in available capacities are applied to the most flexible generation capacities, which were mostly hydro and gas power plants. The resulting power plant and storage capacities, as well as load reduction potentials for the year 2025 are summarized in Table 7 in the Appendix.

3.3 Considered scenarios

In the evaluation of SoS, the appropriate reflection of temporal variations is not only important concerning the outages of conventional power plants, but also concerning electricity demand and VRE power generation. For this reason the scenarios assessed in this work focus on the distinction of different time series of variable demand and generation. We consider two different sets of historic load profiles, reflecting the hourly electricity demand in the years 2012 and 2014. The load of 2012 represents a case in which the peak loads of the considered European countries are highly coinciding, reaching a maximum of 365 GW. This implies situations of very high loads in the overall assessment area and thus a demand for power generation capacity. On the contrary, national peak loads are less coinciding in the load profile of the year 2014, and the maximum load amounts to only 344 GW. We choose this year, as it is used as reference for the calibration of the model calculating the stochastic availability of conventional power plants (see Section 3.1). The hourly power generation of wind turbines and photovoltaic panels depends on solar irradiation and wind speed, respectively. Due to the highly intermittent characteristics of these resources, their output shows very different pattern during the year, but also for selected months and years. For this reason, we consider three historic weather years. They rely on measured high resolution solar irradiation and wind speed data for the years 2006, 2009 and 2010. Both for Europe and Germany, 2006 represents a year with an average availability of wind and solar power, compared to the other years in the period 2006 to 2012 [39]. In contrast, the year 2010 was characterized by a relatively low availability. The solar and wind power generation in the year 2009 was particularly low in the winter months and thus in the times of highest demands. We mix different load and weather years to construct particularly challenging situations of a high peak load and low availability of wind and solar power. Even though cold winter periods are often accompanied by a cloudy and windless weather, there is no clear correlation between solar irradiation and wind on the one hand, and grid load on the other.

To evaluate the impact of the stochastic power plant availabilities it is compared to one scenario with constant availabilities. It uses the average values of the variable power plant availabilities. An additional scenario assesses the impact of a reduced power transmission capacity within Germany. We assume that until the year 2025 only the westernmost of the three planned high-voltage direct current (HVDC) transmission lines can be realized. This reduces the net transfer capacity from northern to southern Germany from 10 GW to 2 GW. Table 4 provides an overview of the scenario input.

Table 4: Summary of the considered scenarios.

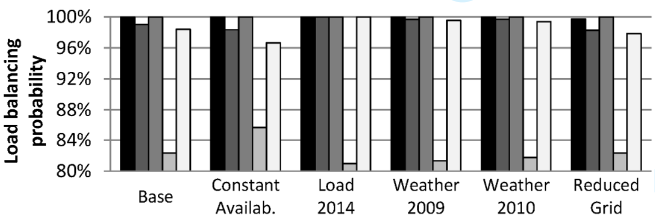
Scenario	**Historic load profile**	**Power plant availability**	**Wind and solar power generation profile**	**North-South HVDC power lines**
Base	2012	Stochastic	2006	3 lines
Constant Avail.	2012	**Constant**	2006	3 lines
Load 2014	**2014**	Stochastic	2006	3 lines
Weather 2009	2012	Stochastic	**2009**	3 lines
Weather 2010	2012	Stochastic	**2010**	3 lines
Reduced Grid	2012	Stochastic	2006	**1 line**

4 Results

With regard to the focus of this paper, the analysis of the model results is restricted to the SoS indicators introduced in Section 2.3. The evaluation of further model output, including technology-specific capacity factors, power flows, CO_2 emissions and supply costs is beyond the scope of this work. Furthermore, the detailed analysis of supply shortfalls is limited to the situation in Germany. Additional results for the other countries are shown in [40].

The appearance of supply shortfalls is directly indicated by the LBP. Values below 100% imply that in at least one hour of at least one variation the load cannot be completely covered by the available power plant and storage capacities considering the available demand response and installed grid capacities. REMix results show that the load can always be covered in all scenarios and variations for all countries except Germany, France and Poland (Figure 6). Within Germany, supply shortfalls appear in only three of the 18 model regions: *Amprion-5* and *Amprion-4* in the western part of the country and *TenneT-3* in the centre (see region map in Figure 5). The region most affected is *Amprion-4*. There, shortfalls appear in all scenarios, in *Amprion*-5 in all scenarios except *Constant Availability* and *Load 2014*, in *TenneT-3* only in scenario *Reduced Grid.* With the exception of Poland, where they hardly exceed 80%, LBP values of more than 96% are found in all regions and scenarios.

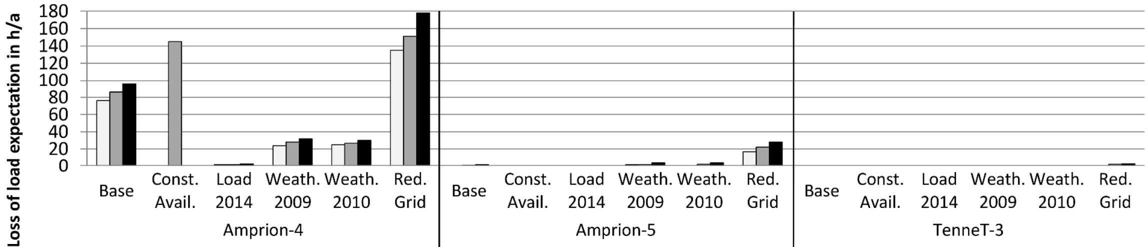
Comparing the scenarios, the highest LBP values for Germany are found in *Load 2014*, where in most variations only one hour is affected. On the contrary, with the load profile of the year 2012 (scenario *Base*), a significantly lower value is detected for region *Amprion-4*. The consideration of weather years with lower availability of solar irradiation and wind both during winter (*Weather 2009*) and during the whole year (*Weather 2010*) has different regional impacts. In region *Amprion-5* it leads to the appearance of supply shortfalls, whereas the LBP is increased in *Amprion-4*. The assumption of constant power plant availability has a negative effect on SoS in *Amprion-4*, but not in the other regions. Finally, lowest values occur in scenario *Reduced Grid* for all affected regions of Germany, indicating the importance of the planned transmission grid expansion for the SoS.



	Base	Constant Availab.	Load 2014	Weather 2009	Weather 2010	Reduced Grid
Amprion-5	100%	100%	100%	99.99%	99.98%	99.75%
Amprion-4	99.02%	98.34%	99.99%	99.68%	99.69%	98.28%
TenneT-3	100%	100%	100%	100%	100%	99.98%
Poland	82.31%	85.61%	80.97%	81.30%	81.74%	82.30%
France	98.40%	96.64%	100%	99.55%	99.39%	97.83%

Figure 6: Load balancing probability (LBP) in the different scenarios. Only regions with values < 100% in at least one scenario are shown.

In accordance with the LBP, the loss of load expectation (LOLE) is highest in region *Amprion-4* (Figure 7). Average values range from 1 h/a in scenario *Load 2014* to 151 h/a in *Reduced Grid.* In region *Amprion-5*, the LOLE is below 4 h/a in all scenarios and variations except *Reduced Grid*, where average and maximum value reach 22 h/a and 28 h/a, respectively. In scenario *Base*, the supply shortfalls of one hour appear only in eleven variations, leading to an average value of 0.04 h/a. Region *TenneT-3* sees supply shortfalls only in scenario *Reduced Grid*, reaching an average duration of 1.4 h/a.



	Amprion-4 Base	Amprion-4 Const. Avail.	Amprion-4 Load 2014	Amprion-4 Weath. 2009	Amprion-4 Weath. 2010	Amprion-4 Red. Grid	Amprion-5 Base	Amprion-5 Const. Avail.	Amprion-5 Load 2014	Amprion-5 Weath. 2009	Amprion-5 Weath. 2010	Amprion-5 Red. Grid	TenneT-3 Base	TenneT-3 Const. Avail.	TenneT-3 Load 2014	TenneT-3 Weath. 2009	TenneT-3 Weath. 2010	TenneT-3 Red. Grid
Min.	76		1	24	25	135	0		0	1	0	17	0		0	0	0	0
Av.	86	145	1.03	28	27	151	0.04	0	0	1.2	1.5	22	0	0	0	0	0	1.4
Max.	96		2	32	30	178	1		0	4	4	28	0		0	0	0	3

Figure 7: Annual loss of load expectation in the German regions where shortages occur.

Figure 8 shows the probability distribution of the LOLE in region *Amprion-4* for the 300 variations of the scenarios. It underlines that the differences between the variations are comparatively small for scenario *Load 2014*, *Weather 2009* and *Weather 2010* and do not exceed 8 h/a. Broader probability distributions are found for scenario *Base* and especially *Reduced Grid*. It can be clearly seen that the range between maximum and minimum value increases with the average LOLE value.

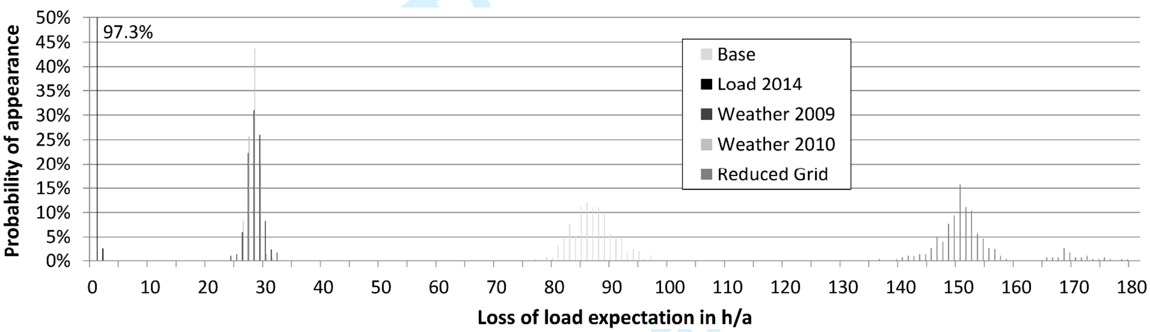
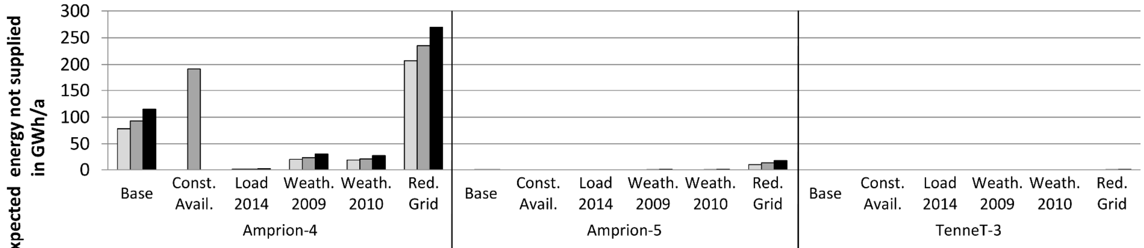


Figure 8: Probability distribution of annual loss of load expectation in region Amprion-4.

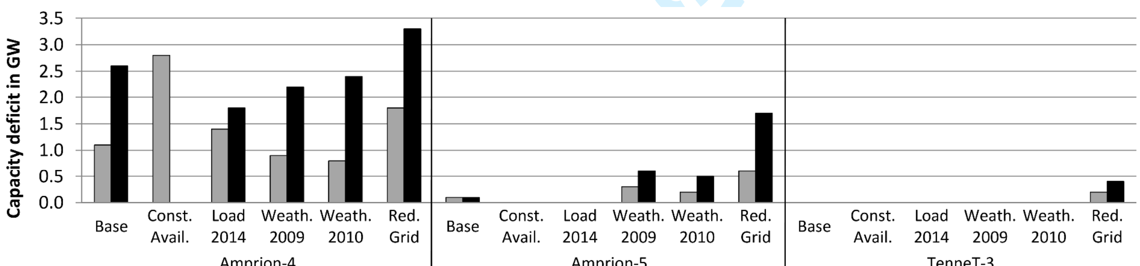
Due to the very few supply shortfalls, the expected energy not supplied (EENS) is very low in the regions *Amprion-5* and *TenneT-3* (Figure 9). It does not exceed 1 GWh or roughly 0.0006% of the annual demand in most scenarios. Only exception is the scenario with reduced transmission capacity in Germany, where on average almost 13 GWh of demand remain uncovered in *Amprion-5*, equivalent to approximately 0.007% of the annual sum. Much higher values are found in region *Amprion-4*: up to 270 GWh of unsupplied load are detected in scenario *Reduced Grid*, accounting for almost 0.1% of the annual demand. The additional power lines in the *Base* scenario can reduce the EENS by more than half to an average of 93 GWh/a. Such as for the LOLE, a higher value is found if constant power plant availabilities are considered. In scenario *Weather 2009* and *Weather 2010*, only about 20 GWh/a cannot be provided, whereas in *Load 2014* the EENS is even lower by another order of magnitude.



	Amprion-4 Base	Amprion-4 Const. Avail.	Amprion-4 Load 2014	Amprion-4 Weath. 2009	Amprion-4 Weath. 2010	Amprion-4 Red. Grid	Amprion-5 Base	Amprion-5 Const. Avail.	Amprion-5 Load 2014	Amprion-5 Weath. 2009	Amprion-5 Weath. 2010	Amprion-5 Red. Grid	TenneT-3 Base	TenneT-3 Const. Avail.	TenneT-3 Load 2014	TenneT-3 Weath. 2009	TenneT-3 Weath. 2010	TenneT-3 Red. Grid
Min.	78		1.2	21	18	207	0		0	0	0	10	0		0	0	0	0
Av.	93	192	1.4	24	22	235	0.0003	0	0	0.3	0.2	13	0	0	0	0	0	0.2
Max.	115		1.9	31	28	269	0.1		0	0.9	0.8	17	0		0	0	0	0.6

Figure 9: Annual expected energy not supplied in the German regions where shortages occur.

The average and maximum capacity deficit are shown in Figure 10. Thereby, the average refers to all hours with unsupplied load. The maximum value indicates the demand for additional power generation or load reduction required to close the identified supply gaps. In region *TenneT-3*, only in scenario *Reduced Grid* a deficit of 0.4 GW at most is detected. In region *Amprion-5*, the maximum capacity deficit reaches 1.7 GW in scenario *Reduced Grid* and is much lower in all other scenarios. The consideration of the below-average availability of solar and wind power leads to an increase from 0.1 GW in scenario *Base* to 0.5 GW and 0.6 GW in *Weather 2010* and *Weather 2009*, respectively. As supply gaps appear only in one hour, maximum and average capacity deficit are identical in scenario *Base*. In region *Amprion-4*, much higher capacity deficits are found. Also in the least challenging scenario *Load 2014*, 1.8 GW of additional generation are required, equivalent to approximately 26% of the assumed regional peak load. In the *Base* scenario, the maximum gap reaches 2.6 GW. Supposing a constant power plant availability or reduced grid availability even higher values of 2.8 GW and 3.3 GW are reached, respectively.



	Amprion-4 Base	Amprion-4 Const. Avail.	Amprion-4 Load 2014	Amprion-4 Weath. 2009	Amprion-4 Weath. 2010	Amprion-4 Red. Grid	Amprion-5 Base	Amprion-5 Const. Avail.	Amprion-5 Load 2014	Amprion-5 Weath. 2009	Amprion-5 Weath. 2010	Amprion-5 Red. Grid	TenneT-3 Base	TenneT-3 Const. Avail.	TenneT-3 Load 2014	TenneT-3 Weath. 2009	TenneT-3 Weath. 2010	TenneT-3 Red. Grid
Av.	1.1	2.8	1.4	0.9	0.8	1.8	0.1	0	0	0.3	0.2	0.6	0	0	0	0	0	0.2
Max.	2.6		1.8	2.2	2.4	3.3	0.1		0	0.6	0.5	1.7	0		0	0	0	0.4

Figure 10: Average and maximum capacity deficit in the German regions where shortages occur.

Figure 11 shows the probability distribution of capacity deficits in region *Amprion-4* in steps of 0.1 GW. In contrast to the other probability distributions, it shows a strong concentration only for scenario *Load 2014*. It can be explained with the very low number of hours with uncovered load of less than two. In all other scenarios, values of a broad range are found. They include all steps from less than 0.1 GW up to the respective maximum gap of each scenario and are not clearly grouped around one single maximum value. This results from the more frequent supply gaps, which are in their extent to a higher degree influenced by the hourly profiles of power plant availability.

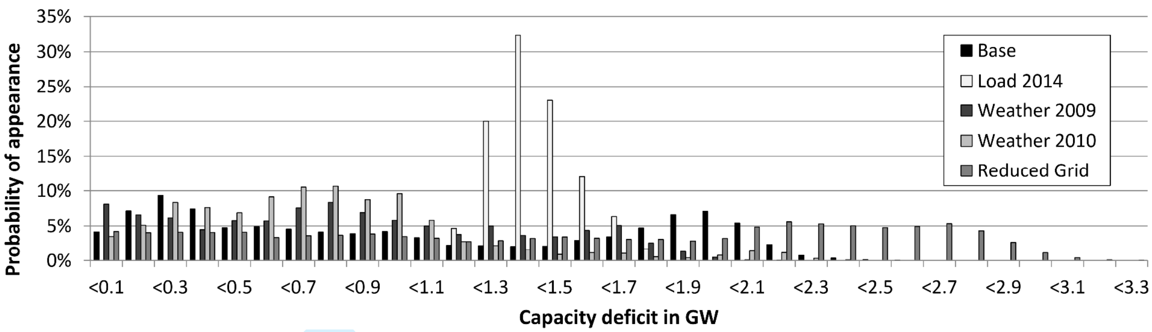


Figure 11: Probability distribution of capacity deficits in region Amprion-4. Hours without deficit are not included here.

Supply shortfalls are not equally distributed over the year. Figure 12 provides the hourly LOLP in scenario *Reduced Grid* for region *Amprion-4*. This scenario represents the case with lowest load balancing probability in Germany. In the graph, a value of one implies a supply shortfall during the corresponding hour in any of the 300 variations, a value of 0.25 a shortfall in 75 of the variations and so on. The REMix results show a strong concentration of shortfalls to the winter months and particularly the first two weeks of February (hour 745 to 1080). In contrast, during the months March to September all demand can be satisfied. The LOLP is one in 130 of the 193 hours with a value greater than zero. This implies that more than two thirds of the shortages occur in all variations, independent of the stochastic availability of conventional power plants.

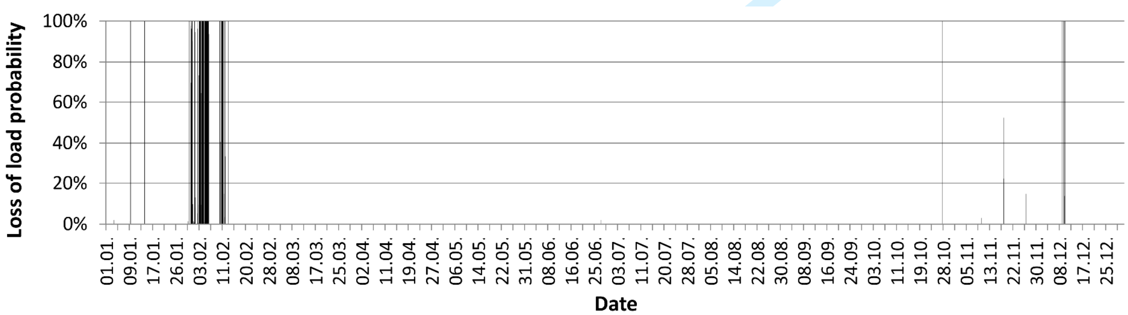


Figure 12: Hourly loss of load probability in region Amprion-4 in the scenario with reduced transmission capacity. Values of 1 imply that a deficit appears in each of the 300 variations of power plant availability.

In region *Amprion-5*, shortfalls also appear only during the winter months and particularly in February, however at a much lower intensity and duration. There, only

14 of the 32 hours with unsupplied load in at least one variation have an hourly LOLP of one. A concentration to the first half of February can be found in all other scenarios as well.

To further examine the load flows between the model regions, the hours with supply shortfalls are analysed in detail for a selected variation of scenario *Reduced Grid*. The analysis reveals that the existing grid capacity from Germany to Poland is fully exploited for exports during almost all hours with supply shortfalls in Poland. In times all demand is met in Germany but not in France, the transmission lines are used for power exports to France by at least 75% in case of the connection to region *Amprion-5* and 40% for the connection to region *TransnetBW-2*. On average, the grid capacity utilization in these hours reaches 94% and 49%, respectively. In hours with shortfalls in both France and region *Amprion-4*, these exports are reduced, but still remain at an average level of 66% and 35%, respectively. This does not change when supply shortfalls furthermore occur in region *Amprion-5*: the average capacity utilization for exports to France is then reduced to averages of 54% and 25%, respectively. A reduction of exports to levels of less than 20% of the grid capacity is observed only in very few hours with deficits in both Germany and France. There are also isolated events with a power import from France to Germany among these hours, using up to 12% of the available grid capacity. The connection between the Netherlands and *Amprion-4* is used for power imports to Germany at full capacity during all hours with supply shortfalls in Germany or France. The additional connections from the Netherlands to the regions *Amprion-1* and *Amprion-2* are also used for imports during these hours, however at lower capacity utilization. In the few hours with supply shortfalls, region *Amprion-5* receives significant imports from *TransnetBW-1.* However, at the same time, it exports to *TransnetBW-2*. Region *Amprion-4* receives power imports from *Amprion-2* during all and from *TenneT-4* during most hours with capacity deficits. However, at the same time it always exports to region *Amprion-5.* The utilization of generation and transmission capacities in critical situations is exemplarily shown in Figure 13 for a selected winter hour in one variation of scenario *Reduced Grid*. In this hour – 10 February, 7-8 PM – supply shortfalls occur in Poland (3.3 GW), France (3.8 GW), *Amprion-4* (1.7 GW) and *Amprion-5* (0.6 GW). Available dispatchable generation capacities – including nuclear, fossil, biomass and reservoir hydro power stations – are fully operational in Poland, Luxemburg, France and most regions in the western half of Germany. Free generation capacities are found in all other neighbouring countries as well as eastern and south-eastern Germany. Considering unlimited transmission, these capacities would be sufficient to close the supply gaps appearing in this particular hour. The analysis furthermore shows that many transmission lines are at their capacity limits, whereas others are used only to a minor extent. High grid utilization rates are found particularly for connections to Poland and *Nordel* as well as in the Alps region.

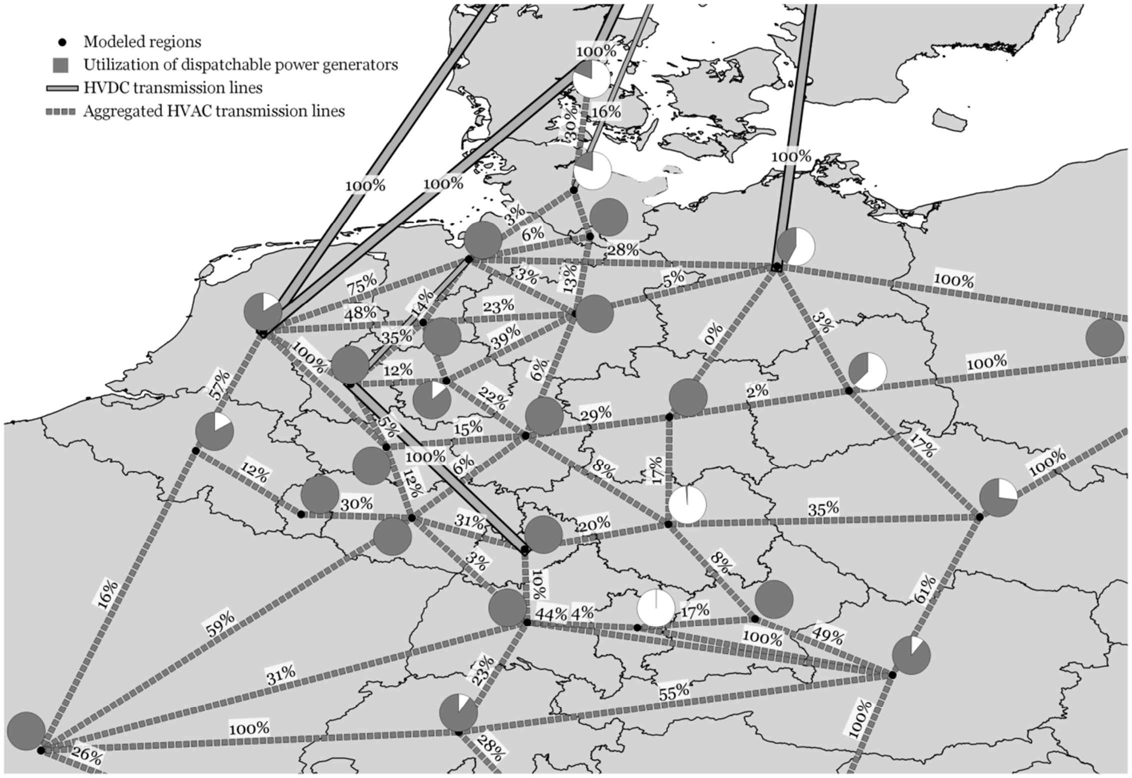


Figure 13: Utilization of generation capacities (pie charts) and transmission capacities (percent numbers) on 10 February between 7 and 8 PM in one variation of scenario *Reduced Grid*.

In the detailed analysis of the capacity utilization of transmission lines in critical supply situations, it appears to be contra-intuitive that firstly, the transmission capacities are not always fully utilized when a region needs imports for meeting the demand and, secondly, certain regions are still exporting power while experiencing shortfalls. The reason for the first lies in the application of direct current power flow constraints which make the desired power flow to a specific importing region not only dependent from the grid transmission capacity of the directly connected transmission line, but also from the limited power flow of transmission lines that are commonly connected to the exporting region. If one of these transmission lines is already fully utilized, further exports or imports are prevented. The second observation can moreover be explained by a limitation of the selected modelling approach that uses an aggregated extract of the existing high voltage transmission grid network. Although it is more likely that the cost intensive artificial electricity generator becomes active in regions with shortfalls, this is not necessarily the case as soon as more than a single region is running into shortfalls. Having in mind that also for times of unsupplied power demand the model produces a cost minimal solution, siting of the artificial power generator in a centrally located region that is able to export and, especially, pass through power to a high number of neighbouring regions appears to be more cost-effective. This artefact of getting a kind of optimal plant siting problem thus causes the exports of centrally located and well-connected *Amprion-4* while lacking of sufficient power supply at the same time.

5 Discussion

High resolution power system models are typically used for the assessment of specific generation or storage technologies, or the development and evaluation of supply scenarios. On the contrary, in this work the REMix energy system model is applied to an assessment of the SoS in the near future until the year 2025. A model endogenous installation of new generation capacities is not considered, and the system cost minimization is mainly driven by the aim to avoid supply shortfalls.

The methodology for the stochastic simulation of power plant availabilities has proven to reasonably realistically reflect the occurrence of unforeseen power station outages. Due to the limited data availability, the simulated power plant availabilities can so far only reflect the pattern registered within a comparatively short period of two years. Furthermore, the model so far only relies on data for Germany. To strengthen the simulations results, future studies must consider additional empirical input data, including both longer periods and further countries. Moreover, a more detailed simulation of power plant unavailability both with respect to refine regional aspects and with respect to power plant specific aspects like fuel supply and river water temperature might bring additional benefit to SoS analysis. As simulation approaches should always cover the statistical behaviour of the basic population of real data, adjusted methodologies might be necessary.

The validity of the results is increased by the analysis of other stochastic factors, namely the hourly development of power demand and VRE power generation. The comparison of different load time series shows that the occurrence of simultaneous load peaks can have significant consequences for the SoS in Germany. In the case of the historic data used here, an additional supply gap appears. The results of scenario *Weather 2009* and *Weather 2010* underline the vital importance of the consideration of different weather years in the evaluation of SoS in energy systems with high VRE share. Even though in the monthly and annual sums, less wind and solar irradiation are available, a reduction in supply shortfalls can be observed in one of the model regions. To gain deeper insight into the interaction between the different stochastic factors, future studies must consider additional load and VRE generation profiles, including both historic and synthetic data.

Scenario *Reduced Grid* allows for an analysis of the importance of the planned HVDC transmission lines in Germany. The REMix results show that a reduction in transmission capacity increases the occurrence of unsupplied load in both northern and southern Germany. However, the growth of the maximum capacity deficit – from 2.6 GW to 3.3 GW – is much lower than the reduction in transmission capacity of 8 GW. This underlines the results of previous REMix studies showing that additional grid capacities can contribute significantly to the integration of VRE power generation, as well as the reduction of emissions and supply costs, but only to a minor extent to a reduction of back-up capacity [41]. Other studies see less capacity deficit. In case of [7,8], the assumed realization of currently planned new power plant capacities and negligence of inner German grid restrictions lead to this conclusion.

Present legislation in Germany foresees various components to ensure the currently high SoS also in the future [42]. Capacity mechanisms are so far not introduced. Despite of capacity payments the evolution of price spikes is favoured. As security measure, several reserves are introduced: A capacity reserve of 2 GW, a security of lignite power plants of 2.7 GW, and a grid reserve for southern Germany of 2 GW. Furthermore, decommissioning of system relevant power plants can be forbidden by the regulating authorities. If needed, reserves can be extended. If these measures are maintained until 2025, they would be sufficient to avoid the supply gaps identified in this work.

In contrast to earlier analyses, this work considers grid restrictions within Germany. Bearing in mind the regional concentration of VRE power generation capacities, this implies a major improvement in the quality of the results obtained here. However, it can be expected that these results are to a high degree dependent on assumed transmission capacities between the regions as well as the regional distribution of power generation. Although it has been determined considering all available data sources, there may be uncertainty as to the actual development of decommissioned and mothballed generation capacity. The results of the case study not only rely on influential assumptions concerning future power plant capacities, but also concerning the future electricity demand. This is important for the overall annual demand, its regional allocation within Germany and even more for the hourly load curve during the year. The spatial disaggregation considered in REMix allows for the identification of regional shortages in power generation and transmission capacity and thus of particularly important power plants and transmission lines. According to the REMix results, supply shortfalls appear in only three of the 18 model regions considered in Germany and show a geographical concentration to the western part of the country close to Luxemburg and France. A more profound analysis of the results indicates that in time of supply shortfalls in those regions, there is still an availability of power plants in other parts within Germany. This result reveals that uncovered demand arises from limitations in transmission capacity within Germany rather than from a deficit in generation capacity. This has to be studied in detail in future work making use of a more detailed representation of the power grid. The use of grid reserve capacities for the purpose of re-dispatch measures is not modelled in this work.

Including these in further analyses might contribute to more robust model results, especially with regard to the regional occurrence of shortfalls. It is important to keep in mind that the SoS as it is defined here does not consider an N-1 criterion. Moreover, if the system is supposed to be secured against an unforeseen failure of the biggest generation unit, additional power plants or transmission lines are likely to be required.

The results presented have been obtained using a simplified model representation of technologies. The REMix modelling approach does not reflect all restrictions in power station operation as well as power transmission. This includes the negligence of minimum operation and down times of thermal power plants, limitations in ramping speed or non-linear effects in power transmission and can lead to an overestimation of the flexibility provided by power plants [17].

The model results emphasize the importance of an international assessment of SoS. Supply shortfalls are not only found in Germany, but also in Poland and France. It can be expected that the substantial capacity deficits in the neighbouring countries do have an effect on the SoS in Germany. On the other hand, an installation of additional generation capacity in those countries might also be available to reduce or even eliminate the uncovered load in Germany. The particularly high capacity deficits in Poland arise from the comparatively old power plant park found there, combined with the global assumption that all power plants are decommissioned end the end of their technical lifetime. Given that most supply shortfalls in Germany occur in the western part of the country and due to grid restrictions, it can be expected that additional generation capacity in Poland has only limited impact on the results presented here. In contrast to that, new capacities or longer lifetimes in France are likely to increase the SoS in southwestern Germany. The interrelation of the SoS in different countries is underlined by the results of scenario *Reduced Grid.* The reduced transmission capacity within Germany assumed there has a significant impact on the amount of unsupplied load in the neighbouring countries as well. In this regard, it is important to keep in mind that grid restrictions within the neighbouring countries are not considered, potentially causing an overestimation of SoS in these countries.

The assumption of identical lifetimes for all power plants of a certain technology, independent of its location and the availability of substituting capacity, leads to substantial reductions in power plant capacity until the year 2025. These reductions do not have the same effect on the SoS in different countries. In spite of a shutdown of more than 55% of the respective conventional generation capacities, no supply shortfalls appear in Denmark and the *Nordel* region. On the other hand, the capacity reduction in France accounting for about 35% has a major impact on SoS. The methodology for the estimation of power plant lifetimes is consistent and transparent.

It does, however, neglect the possibility of lifetime extensions and construction of new power plants, whether they are economically or politically driven. In this context, it is important to emphasize that the results presented here are only valid for the assumed changes in power generation, storage and transmission capacity. This is particularly important for the applied reduction in conventional generation capacity, but also the development of renewable energy technologies, as well as the installation of additional storage and grid capacities. The impact of an even faster reduction of conventional power plant capacity is assessed in [40].

The assumption of a full availability for power generation of CHP plants in critical load situations might cause an overestimation of SoS. If heat cannot be provided completely by additional heat sources, such as boilers or thermal storage, but must be partially supplied by CHP units with variable extraction of useful heat, additional deficits might occur in winter times with high demand for both heat and power.

This work does not address the questions of which technologies would be suited best for closing the identified supply shortfalls, and where those technologies should be deployed. Depending on the operation hours, periods of capacity deficits and geographic location, options might include a strengthening of the power grid, the activation of additional demand response potentials, an enhanced coupling between energy demand sectors, as well as the installation or retrofit of power generation or storage capacity. The evaluation of technology deployment paths is, however, beyond the scope of this paper and must be analysed in future research works.

6 Conclusion

Our analysis underlines that the evaluation of SoS in systems with substantial VRE shares requires the application of advanced methodological approaches. The stochastic simulation of power plant availabilities combined with the model-based analysis of 300 scenario variations in hourly and regional resolution clearly improve the methodological basis of SoS assessments, compared to the application of constant values. The REMix results show that the negligence of the variability of both regular and unforeseen power station outages can cause either an overestimation or underestimation of SoS. The temporal occurrence of unplanned power plant outages can be realistically reflected by the application of a combined Mean-reversion Jump-diffusion process.

The comparison of the scenarios and variations assessed here indicates that the fluctuations in power demand and VRE generation have a much higher influence on the frequency and extent of supply shortages than unforeseen power plant outages. Differences in the results are much bigger for the scenarios than for the variation in power plant availability.

Assuming the decommissioning of power plants at the end of their lifetime, the extension of renewable energy and the expansion of the transmission grid according to the scenarios considered here, at least 2.6 GW of additional capacity will be required in Germany by the year 2025 to guarantee SoS in certain market conditions. A delay in the installation of HVDC transmission lines in Germany increases this value to 3.3 GW. This underlines the importance of additional transmission capacity within Germany for the SoS. Even under the assumption of a delayed commissioning of the HVDC lines, the maximum supply gap in Germany stays below both the currently planned new installation of power plants and capacity reserve. Even though the realization of new generation capacities is not clear, there would still be enough time for further generation and infrastructure expansions.

The methodology applied in this work can provide an improved but still coarse indication of when and possibly where supply shortfalls may appear in the considered scenarios. Any political or corporate decision on investments in generation or grid capacity must rely on models that are more detailed not only in the representation of technologies, but also in spatial and temporal resolution. The latter concerns operational restrictions of power plants, as well as short-term fluctuations in demand and VRE generation.

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Additional Information

Table 5: Assumed net transfer capacities between model regions in the scenario year 2025. High voltage direct current lines are indicated by "HVDC".

International links	Start-End	End-Start	Links within Germany	Start-End	End-Start
	MW	MW		MW	MW
Austria - Czech Rep.	600	1000	Amprion 1 - Amprion 2	2900	2900
Austria - Amprion 6	1000	1000	Amprion 1 - Amprion 3	2700	2700
Austria - TransnetBW 2	1700	1700	Amprion 1 - TenneT 2	2900	2900
Austria - TenneT 6	2800	2800	Amprion 1 - TenneT 3	2000	2000
Austria - Italy	220	285	Amprion 2 - Amprion 3	3900	3900
Austria - Switzerland	470	1200	Amprion 2 - Amprion 4	9300	9300
Belgium - France	5300	6400	Amprion 3 - TenneT 4	1700	1700
Belgium - Netherlands	2400	2400	Amprion 4 - Amprion 5	6500	6500
Czech Rep. - TenneT 5	1800	1800	Amprion 4 - TenneT 4	2000	2000
Czech Rep. - 50Hertz 4	1840	1840	Amprion 5 - TransnetBW 1	2900	2900
Czech Rep. - Poland	800	1800	Amprion 5 - TransnetBW 2	4200	4200
Amprion 1 - Netherlands	2400	2400	Amprion 5 - TenneT 4	4300	4300
Amprion 5 - France	1100	1100	Amprion 6 - TransnetBW 2	4600	4600
Amprion 5 - Luxemburg	1880	1880	Amprion 6 - TenneT 6	2200	2200
TransnetBW 2 - France	1900	1900	TransnetBW 1 - TransnetBW 2	13000	13000
TransnetBW 2 - Switzerland	4000	4000	TransnetBW 1 - TenneT 5	4200	4200
TenneT 1 - Denmark_W	1500	1500	TenneT 1 - TenneT 2	5600	5600
TenneT 2 - Netherlands	1283	1283	TenneT 1 - 50Hertz 2	1792	1792
50Hertz 1 - Poland	600	600	TenneT 2 - TenneT 3	5800	5800
50Hertz 4 - Poland	600	600	TenneT 2 - 50Hertz 1	150	150
France - Italy	4975	3395	TenneT 3 - TenneT 4	5400	5400
France - Switzerland	3200	1100	TenneT 3 - 50Hertz 1	3389	3389
Italy - Switzerland	1810	4165	TenneT 3 - 50Hertz 2	2166	2166
Amprion 4 - Netherlands	1200	1200	TenneT 4 - TenneT 5	4200	4200
Luxemburg - Belgium	1300	1300	TenneT 4 - 50Hertz 3	2272	2272
Amprion 2 - Netherlands	13900	13900	TenneT 5 - TenneT 6	4900	4900
Netherlands - Nordel (HVDC)	700	700	TenneT 5 - 50Hertz 3	5752	5752
Denmark_W - Netherlands (HVDC)	700	700	50Hertz 1 - 50Hertz 3	3320	3320
Denmark_W - Nordel (HVDC)	2400	2400	50Hertz 1 - 50Hertz 4	5920	5920
TenneT 1 - Nordel (HVDC)	2000	2000	50Hertz 3 - 50Hertz 4	10340	10340
50Hertz 1 - Nordel (HVDC)	1200	1200	Amprion 3 - TenneT 3	300	300
Poland - Nordel (HVDC)	600	600	50Hertz 2 - TenneT 2	1800	1800
			50Hertz 3 - Amprion 6 (HVDC)	2000	2000
			Amprion 2 - TransnetBW 1 (HVDC)	2000	2000
			Amprion 2 - TenneT 2 (HVDC)	2000	2000
			TenneT 1 - TransnetBW 1 (HVDC)	6000	6000

Table 6: Calculated power plant lifetimes, subdivided by fuel

	Hard coal	Lignite	Natural Gas	Oil	Other
	All values in years				
Average lifetime of all power plants at decommissioning	39.7	46.9	34.5	39.2	37.3
Average lifetime of power plants that have exceeded the average value at decommissioning	43.3	51.2	40.7	40.1	40.4

Table 7: REMix model input: power plant capacities and electricity demand.

	CCGT	Gas turbine, Engine CHP, Oil	Hard coal	Lignite	Nuclear	Biomass	Reservoir hydro	Hydro run-of-the-river	Total dispatchable capacity	PV	Wind Offshore	Wind Onshore	Pumped storage Hydro	Load reduction potential	Power demand	Peak Load 2012	Peak Load 2014
	GW	GW	GW	GW	GW	GW	GW	GW	GW	GW	GW	GW	GW	GW	TWh	GW	GW
Austria	1.60	1.35	0.46			1.12	3.79	6.89	8.32	0.87		4.51	4.29	0.06	60.6	10.2	10.1
Belgium	6.66	0.45	1.16		2.82	1.78		0.18	12.86	4.30	2.35	3.52	1.31	0.35	75.1	12.6	11.7
Czech Republic	0.98	0.47	3.35	6.10	3.73	0.67	0.74	0.45	16.03	2.04		0.35	1.15	0.09	54.6	9.4	8.8
Germany Amprion 1	1.84	0.13	0.79			0.19		0.00	2.95	1.16		1.11		0.29	10.3	1.6	1.6
Germany Amprion 2	2.57	0.59	2.51	2.29		0.26		0.03	8.22	2.19		1.58	0.15	1.33	50.4	8	7.9
Germany Amprion 3	1.00	0.19	2.67			0.30	0.01	0.07	4.16	1.64		2.55		0.21	28.9	4.6	4.5
Germany Amprion 4	2.23	0.56		1.32		0.19		0.12	4.31	1.92		2.09		0.37	42.1	6.7	6.6
Germany Amprion 5	1.62	0.49	2.24	0.00		0.27		0.25	4.63	3.65		4.63		0.31	47.7	7.6	7.5
Germany Amprion 6		0.18				0.25		0.60	0.43	2.65		0.23		0.23	9.7	1.5	1.5
Germany TransnetBW 1	0.54	0.33	2.37			0.20		0.32	3.44	1.52		0.85		0,04	15.2	2.4	2.4
Germany TransnetBW 2	0.06	1.03	0.82			0.59	0.89	0.95	3.39	5.30		1.90	0.13	0.38	45.4	7.2	7.1
Germany TenneT 1	0.07	0.12	0.33			0.40		0.00	0.92	2.50		7.09	0.12	0.02	11.5	1.8	1.8
Germany TenneT 2	0.61	0.22	1.20			0.64		0.00	2.68	2.88	8.80	6.42		0.25	21.7	3.5	3.4
Germany TenneT 3	0.34	0.23	1.39	0.35		0.62		0.09	2.93	1.95		4.70		0.16	26	4.1	4.1
Germany TenneT 4	0.09	0.54	0.14	0.03		0.27		0.06	1.07	2.51		2.73	0.87	0.07	17.7	2.8	2.8
Germany TenneT 5	0.07	0.31	0.05			0.53	0.17	0.66	1.12	5.54		2.55	0.47	0.05	24.7	3.9	3.9
Germany TenneT 6	1.91	0.28	0.80			0.75	0.05	1.13	3.79	6.70		0.07	0.11	0.12	29.2	4.7	4.6
Germany 50Hertz 1	1.23	0.94	1.13			1.07		0.01	4.37	5.68	1.70	13.81		0.42	30.2	4.8	4.7
Germany 50Hertz 2	0.29	0.19	2.11			0.01		0.00	2.60	0.09		0.08		0.39	8.7	1.4	1.4
Germany 50Hertz 3	0.80	0.68	0.04	2.02		0.46	0.14	0.06	4.15	3.66		4.89	1.46	0.31	23	3.7	3.6
Germany 50Hertz 4	0.22	0.59	0.01	6.28		0.42		0.09	7.52	4.27		2.92	1.16	0.16	23.5	3.7	3.7
Nordel	1.76	1.19	0.62		2.39	6.28	35.96	10.60	48.19	1.13	2.75	9.61	1.46	2.12	242.6	43.8	44
Denmark_W	0.65	0.85	0.44			0.29		0.01	2.23	0.07	1.56	3.16		0.00	17.7	3.2	3.2
France	7.06	3.66	0.37		40.46	4.28	5.91	16.93	61.74	9.93	9.84	29.52	1.17	1.32	431.1	90.4	76.8
Italy	39.20	8.45	2.80			4.40	3.57	15.26	58.42	25.34	1.98	16.02	6.44	0.84	275.1	46	46
Luxembourg	0.40	0.03				0.09	0.00	0.04	0.52	0.35		0.26	0.66	0.06	5.4	0.9	0.9
Netherlands	17.74	2.37	2.81		0.43	2.11		0.07	25.46	1.03	7.08	4.72		0.31	96.3	15.9	16
Poland	0.16	0.16	7.90	4.40		1.29	0.23	1.03	14.15	0.35	2.08	6.25	1.47	0.27	126.7	20.7	20.4
Switzerland	0.15	0.17			2.06	1.08	7.81	4.39	11.25	1.66		0.94	3.79	0.05	56.5	10	9.5

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